I just read through the Federal Register Notice and slides from a Gulf Terra presentation to DOT. I am aware that various groups are discussing and recommending the elimination of hydrotest requirements for deepwater gas pipelines. The hydrotest is viewed by some as an unnecessary operation that only adds to the difficulty and expense of building pipelines. I have always taken the opposite view, and continue to support the retention of a 1.25 x MAOP hydrotest for newly constructed pipelines, for the following reasons:

1. Hydrotest represents a final check that all the quality steps leading to a finished pipeline have been met, including those associated with the manufacture, inspection, coating, transportation, and inspection of line pipe and fittings, and those associated with the weld preparation, welding, non-destructive testing, field joint coating, inspection, and overall pipe handling experienced during offshore pipeline construction.

2. Rather than suggesting that the care taken in performing the above quality steps represent sufficient reason to eliminate the hydrotest, I prefer to view the hydrotest as the primary motivation for any operator to perform all quality steps with care. Humans make mistakes. Therefore, it appears prudent to retain this means of applying pressure on pipeline project managers to eliminate as many errors as possible.

3. The consequences of a leaking hydrocarbon pipeline are great. Adverse public opinion could force the shut-in of significant portions of our offshore oil production in the event of a major crude oil pipeline break. It is much better to verify that the pipeline is free of leaks before hydrocarbons are introduced, and at a time when the general contractor is still available to make timely repairs. It is also appropriate, in conjunction with the hydrotest, to run a sizing pig to verify that a rare buckle or major dent has not gone unnoticed during construction.

4. Ultimately, eliminating hydrotesting for everyone, would introduce the possibility of shoddy materials and shoddy workmanship, and more premature failures, creeping into our pipeline networks.

5. In general, the hydrotest issue is about small leaks, not about burst or collapse failures. For example, if designed according to the design limits in the API RP 1111, actual minimum burst pressure of new pipe would exceed MAOP by 54 % (P/Pb = .648) for pipelines, and by 85 % (P/Pb = .540) for risers, and collapse pressure would exceed maximum external seawater pressure by 43 % for seamless pipe, or 67 % for DSAW pipe. (There is recent evidence that the 67 % can be reduced to 50 % or so if the DSAW pipe is heated to more than 400 deg-F during the external coating process.)

6. The Phoenix pipeline indeed will be conservative, since the 18" x 0.75" pipeline burst pressure exceeds MAOP be 116 % (P/Pb = .462), the 18" x 0.875" riser burst pressure exceeds MAOP by 140 % (P/Pb = .417), and the 18" x 0.791" pipeline collapse pressure exceeds hydrostatic at 5300-ft depth by 70 % (P/Pc = .589). The internal pressure limits are even more conservative than indicated, since I have not taken into account the considerable external pressure surrounding the pipeline. However, in spite of this additional conservatism beyond the minimum code requirement, I remain convinced that such conservatism is urelated, and has very little affect on, the hydrotest, which is primarily a quality control issue.

As pipeline technology progresses into ever deeper waters, it is conceivable that there will occur isolated cases of gas transmission pipelines, for which the cost of dewatering these pipelines following hydrotest truly becomes prohibitive. I do not believe, at 5300-ft depth, that Gulf Terra has reached such ultimate limit. However, that decision rests in your hands at the Department of Transportation.

I hope these comments will be useful to you.

Sincerely, Carl Langner